

Editor's note: 98 I.D. 409 Reconsideration granted; decision reaffirmed as modified. See 121 IBLA 252A th E (Oct. 2, 1992) below, 99 I.D. 191

EXXON COMPANY, U.S.A.

CHEVRON U.S.A., INC.

IBLA 88-233, 88-234

Decided November 15, 1991

Appeals from a decision of the Director, Minerals Management Service, denying appeals from a letter decision requiring lessees to bear the costs of treating gas produced from lease No. OCS-P 0441. MMS 87-0335-OCS and MMS 87-0321-OCS.

Affirmed.

1. Oil and Gas Leases: Royalties: Processing Allowance--Outer Continental Shelf Lands Act: Oil and Gas Leases

The term "treatment," as identified in 30 CFR 250.42 (1987), is the removal or extraction of chemical impurities or contaminants that must be removed in order for the gas to be of marketable quality or to place the gas in a marketable condition. "Sour gas" is gas contaminated by hydrogen sulfide or other sulphur compounds, which must be removed before the gas can be used for commercial and domestic purposes. The sulphur contaminants are not liquid hydrocarbons, so that their removal is not "processing" under 30 CFR 206.152 (1987). Removing the hydrogen sulfide (sweetening the gas) is "treatment" within the meaning of the regulations.

2. Oil and Gas Leases: Royalties: Generally--Outer Continental Shelf Lands Act: Oil and Gas Leases

The costs of "treatment" or other costs necessary to place the gas in marketable condition are not deductible

or chargeable against the Federal royalty interest. It is irrelevant who performs the treatment or the activities necessary to place the gas in marketable condition, or that title may have passed from the Federal lessee prior to undertaking the activity necessary to place the gas in marketable condition. MMS' decision barring lessees from using an 88-percent price-reduction factor in the computation of royalty on natural gas will be affirmed where costs represented by the factor were incurred in the process of extraction of hydrogen sulfide (sweetening), which was necessary to place the natural gas in marketable condition.

APPEARANCES: Salvatore J. Casamassima, Esq., Houston, Texas, for Exxon Company, U.S.A.; Cynthia A. Norris, Esq., San Francisco, California, for Chevron U.S.A., Inc.; Peter J. Schaumberg, Esq., Geoffrey Heath, Esq., and Howard W. Chalker, Esq., Office of the Solicitor, U.S. Department of the Interior, Washington, D.C., for the Minerals Management Service.

OPINION BY ADMINISTRATIVE JUDGE HUGHES

Exxon Company, U.S.A. (Exxon), and Chevron U.S.A., Inc. (Chevron), have filed separate appeals from a December 18, 1987, decision of the Director, Minerals Management Service (MMS), denying their appeals from letter decisions of the Chief, Royalty Valuation and Standards Division, prohibiting the inclusion of an 88-percent price-reduction factor in the computation of royalties on natural gas produced from lease No. OCS-P 0441. 1/ Because these cases present similar factual and legal issues, we have consolidated them.

1/ Chevron appealed to the Director from a June 1, 1987, letter decision and Exxon from a June 5, 1987, letter decision. Exxon's appeal from the Director's Dec. 18, 1987, decision was docketed as IBLA 88-233 and Chevron's as IBLA 88-234.

Union Oil Company of California (Union) is a working interest owner in, and the designated unit operator of, the Point Pedernales Unit (Unit), Santa Maria Area, offshore California. That Unit embraces several leases, including OCS-P 0441. Union is not a party to these appeals. Chevron and Exxon, along with other parties, are co-lessees and nonoperating working interest owners in the Unit. The Unit produces oil and "sour" natural gas, that is, gas containing a high percentage of hydrogen sulfide as well as other sulphur compounds. 2/

The facts giving rise to the present appeals are not substantially in dispute. Prior to the commencement of initial production from the Unit, Union, as unit operator, advised MMS:

Natural gas produced from the Unit is transported from the Platform Irene, the Unit production platform, via undersea pipeline to the Lompoc Heating, Separating and Pumping facilities (Lompoc H.S. & P.). The custody transfer point for natural gas is located at the Lompoc H.S. & P. and is the gas measurement meter (FE-640) downstream of the gas pipeline Inlet Scrubber (Vessel V-100) and downstream of the three inch (3") piping connection which delivers associated gas evolved off of the Lompoc H.S. & P. gas handling facilities into the gas pipeline. [Footnote omitted.]

(Feb. 16, 1987, Letter at 1).

Union stated that it was responsible for the delivery of all "unitized hydrocarbon substances" to the designated custody transfer

2/ "Sour gas" has been defined by Williams and Meyers as "[n]atural gas contaminated with chemical impurities, notably hydrogen sulfide or other sulphur compounds, which impart to the gas a foul odor. Such compounds must be removed before the gas can be used for commercial and domestic

points for receipt by the working interest owners and/or royalty interest owners as might be necessary: "Each working interest owner and/or royalty interest owner receives its share of natural gas in kind at the custody point and is responsible for disposition of the gas thereafter."

Union described how its own undivided working interest share of gas produced from the Unit was handled:

Union intends to receive its share in kind of the Unit produced gas, including the royalty portion thereof, at the custody transfer point and transport the gas via a Union owned pipeline to Union's Battles Gasoline Plant [(Battles Plant)] for treating and processing. The Unit produced gas contains significant amounts of CO₂ [(carbon dioxide)] and H₂S [(hydrogen sulfide)] and is not of a marketable quality without treating. The residue gas remaining after treating for CO₂ and H₂S content and processing for liquid hydrocarbon recovery will be retained by Union for internal disposition as fuel gas for Union's plant and field facilities. [Emphasis supplied.]

(Feb. 16, 1987, Letter at 2).

In this letter Union proposed, for purposes of computing royalty on gas production from the Unit, "to establish the value of the natural gas based upon the price provisions and price which the Southern California Gas Company (SoCalGas) [was then] currently offering in new gas purchase contracts in the Southern California area," which was: "Price, \$/MMBtu = (0.60 X SACOG) X 0.88."

fn. 2 (continued)

purposes." Accord Thompson v. Consolidated Gas Utilities Corp., 300 U.S. 55, 59 n.3 (1937) (referring to sour gas as "gas contaminated by sulphur compounds").

The "SACOG" is the Southern California Gas Company's monthly average cost of gas, expressed on a dry unit heating value basis, that is determined by SoCalGas for 6 months ending June 30 and December 31 of each contract year by reference to the actual average cost per decatherm, weighted by quantity, of all gas purchased by SoCalGas during the 6 months preceding the date of such determination. The SACOG was inclusive of all gas purchased by SoCalGas and delivered into SoCalGas gas distribution and transmission facilities in the State of California for such applicable period.

Sixty percent of the SACOG ($0.60 \times \text{SACOG}$) represented the pricing provision established by SoCalGas for new gas purchase contracts in the Southern California area. Sixty percent was the "discount factor" then being offered by SoCalGas. This discount factor is not in dispute in this appeal.

The 88-percent factor (0.88) was described as "a processing factor to account for plant fuel and plant losses incurred in the treating and processing at Union's Battles Plant." It is this factor that is at issue in these appeals.

Pursuant to gas purchase contracts dated March 2 and April 8, 1987, respectively, Chevron and Exxon agreed to sell their working interest shares of the Unit gas to Union at the custody transfer point at the same price identified by Union and described above. The gas purchase contracts each provided that sellers (Chevron and Exxon) had to deliver their working

interest shares of gas in its "natural state" to the "[d]elivery point." ^{3/} Chevron and Exxon do not deny that their working interest share of gas was sour in its natural state. Nor do appellants deny that their respective working interest share of gas was being sweetened at the Battles Plant.

The price provisions in Union's respective gas purchase contracts with Exxon and Chevron refer to the same 88-percent factor identified by Union above. Union's gas purchase contracts with Chevron and Exxon refer to the 88-percent factor as a "processing factor to account for plant fuel and loss for which Buyer is liable" (Chevron-Union Gas Purchase Contract at 7; Exxon-Union Gas Purchase Contract at 13).

MMS' Royalty Valuation and Standards Division, in letter decisions dated June 1, 1987, to Chevron, and June 5, 1987, to Exxon, instructed that, in computing royalty on gas, Chevron and Exxon "may not include the factor of 0.88 or any other factor which represents a price reduction for costs to place the gas in marketable condition." Supporting this determination MMS attached "Findings and Conclusions," stating:

The Unit gas contains high amounts of CO₂ and H₂S and is not of marketable quality without treating. Unit gas is expected to contain 10 to 11 percent CO₂ by volume; the Amine treatment unit at the Battles plant will lower this percentage to 7.5 percent. An "iron sponge" absorption system will be utilized for partial removal of the H₂S and other contaminants; the resulting chemical effluent will then be disposed of. The residue gas

^{3/} The "delivery point" is Union's gas sales meter (FE640) downstream of the gas pipeline Inlet Scrubber (Vessel V-100) and downstream of the 3-inch connection which delivers associated gas off of the Lompoc Heating, Scrubbing and Pumping Facility. This delivery point is the same as that identified by Union for receipt and metering of its own working interest share of gas.

remaining after treatment and processing at the Battles Plant is to be retained by [Union] for use as fuel gas in its plant and field facilities.

(Findings and Conclusions Attachment to June 1, 1987, Letter to Chevron and June 7, 1987, Letter to Exxon). MMS stated further that the 88 percent "represents [Union's] costs at the Battles Plant to upgrade the gas so it is usable in Union's plant and field facilities." Id. Chevron and Exxon both appealed to the Director, MMS.

On May 14, 1987, MMS transmitted a similar letter to Union outlining the facts referenced above and additionally stating that gas plant liquids were to be sold to third parties at posted prices, and that no marketing of the removed CO₂ was planned. Union evidently did not appeal.

Union, while not a party to Chevron's and Exxon's appeals pending before the Director, submitted a letter to the Director, dated August 10, 1987, in support of Chevron's Notice of Appeal, stating:

Union wishes to advise that the principal contaminant at this time which makes the gas unmarketable is H₂S rather than CO₂. Nonetheless, the gas as received by Union at the custody transfer point, must be processed even for use as fuel gas due to the high H₂S content, otherwise burning as fuel gas would result in violations of prevailing Air Pollution Control District permit conditions. The Unit gas contains approximately 1300 ppm of H₂S which is considerably greater than the gas sales contract specification limits of 20 grains or 318 ppm. However, Union has agreed to continue to purchase the high H₂S content gas so long as sufficient capacity exists at its Battles plant facility to safely remove and handle the H₂S.

* * * * *

MMS states that the "0.88 is a price reduction included by [Union] to reflect its cost at the Battles Plant to upgrade the gas so it is usable in [Union's] plant and field facilities." Union wishes to advise the MMS that the 0.88 factor is not related in any way to processing, treating or upgrading the Unit gas but is in fact a reduction factor to offset costs incurred by Union in gathering and compressing the gas to move it into, and through, Union's Battles Plant and also to account for metering, handling losses and pipeline losses for the pipelines, facilities and plant. On a historical basis, Union's compression, plant and field fuel consumption average 9% for each MMBtu of gas handled in Union's Battles Plant field and plant facilities. Unaccounted for losses such as metering, handling and pipeline usually average 3% for each MMBtu of gas handled in Union's Battles Plant field and plant facilities. The total of these two items, 12%, is the basis for the 0.88 factor ($1.00 - 0.12 = 0.88$). At the time the gas sales contracts were negotiated with the Unit working interest owners this derivation and justification for the 0.88 factor was relayed to each of the parties and under no circumstances were the charges ever implied to be, or justified as, processing and/or treating costs. In fact each of the gas sales contracts between Union and the other working interest owners defines the 0.88 factor as "processing factor to account for plant fuel and loss for which Buyer is liable for." [Emphasis supplied.]

On December 18, 1987, the Director, MMS denied appeals filed by Chevron and Exxon, finding:

While it is not entirely clear from the record whether the 0.88 price reduction factor was attributable to costs associated with treatment of the gas, or to line losses or gathering costs, or to some combination thereof, the result is the same. Under the regulations, none of the above are allowable deductions for royalty valuation purposes.

(Director, MMS, Decision at 8). From the Director's decision, these appeals ensued.

[1] The pre-1988 offshore regulations provided at 30 CFR 250.42 (1987): "The lessee shall put into marketable condition, if commercially feasible, all products produced from the leased land. In calculating the royalty payment, the lessee may not deduct the costs of treatment." ^{4/} Thus, the lessee, in calculating royalty, may not deduct costs of "treatment" in determining the royalty basis of production from the lease. In contrast, the pre-1988 offshore regulations did provide an allowance for expenses incurred when "gas is processed for the recovery of constituent products." 30 CFR 206.152 (1987). ^{5/} Viewed against this background, it is evident that the distinction between "processing" and "treatment" is critical in calculating royalty due.

We note that the distinction between "treatment" and "processing" has significance only in the Federal royalty context. In private leases, while the royalty owner is not typically required to bear any production costs (except as otherwise provided by contract), the royalty interest does bear a proportionate share of the costs to market the lease products, including the costs of placing the gas in a marketable condition, be those costs _____

^{4/} Except for a change of section number, that provision has remained substantially intact since it first appeared in the first set of offshore regulations effective May 10, 1954. In 1954, 30 CFR 250.41 provided pertinently: "(b) The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment." 19 FR 2658 (May 8, 1954).

^{5/} The pre-1988 onshore regulations are more specific, providing for an allowance for the extraction of "casing-head or natural gasoline, butane, propane, or other liquid hydrocarbon substances extracted from the gas produced on the leasehold." 30 CFR 206.106.

"treatment" or "processing" costs. Hence, in the private lease context, so long as the royalty interest shares in post-production or marketing costs, it is immaterial as to how those costs are classified. 3 Williams and Meyers, Oil and Gas Law §§ 642, 642.3, 645, 645.2 (1990). Because the classification of such costs is largely immaterial in the private lease context, cases employing these terms employ them interchangeably and accordingly provide little aid in distinguishing them as they are used in Federal lease matters.

According to one respected authority, the terms "processing" or "manufacturing," under the pre-1988 Departmental regulations, plainly contemplated the removal or extraction of liquefiable hydrocarbons from wet gas or casinghead gas. 8 Williams and Meyers, Oil and Gas Law § 750-1 (1987). The "constituent products" referenced in the "processed gas" regulation are those liquid hydrocarbons separated or extracted out (by means beyond normal lease or field separation) from the dry natural gas stream (methane), that is, "natural gasoline, butane, propane." 30 CFR 206.152(a)(2); 250.63(a) (1987). ^{6/}

The 1974 Conservation Division Manual (CDM) provided a similar definition of "processing":

The term "manufacturing" is synonymous with the terms "extraction" or "processing."
A manufacturing allowance is proper for most

^{6/} The Director held that what distinguishes treatment and processing is the creation of "a new, chemically distinct product." While MMS' assertion may be in concert with post-1988 regulations, we can find no support for this interpretation in regulations in effect in 1987, the Conservation Division Manual, or Board precedent.

processes which are designed to extract hydrocarbon liquids from a natural gas by altering pressures, temperatures, or introducing extraneous material, (including absorption, adsorption, refrigeration, or combinations thereof). [7/; emphasis supplied.]

CDM 647.3.3 (5-17-74 (Release No. 12)). Based on the above, we conclude that "processing," as it was used in the pre-1988 regulations, embraced only the removal of hydrocarbon liquids from the natural gas stream.

In reaching this conclusion, we find it significant that MMS deemed it necessary to modify the definition of "processing" in January 1988 to include the extraction of non-hydrocarbon substances. See 30 CFR 206.101 (1988) and 30 CFR 206.151 (1988); 8 Williams and Meyers, Oil And Gas Law § 154 (Supp. 1990). In proposing the new definition of "gas," which was later incorporated into the new definition of "processing," MMS stated:

Existing valuation regulations[, that is, those operative in 1987 and applicable in this case,] were written to deal primarily with hydrocarbon gas streams. This was especially true when dealing with processed gas. In the last decade, the existing regulations proved difficult to administer when handling gas mixtures of diverse content. Gas plants have been constructed to process gas mixtures where some gas plant products may not be a hydrocarbon. In order to accommodate processing plants that process and sell nonhydrocarbon production, the term "gas," will commonly apply to the total gas mixture as it enters the plant. The term "residue gas" will refer to gas consisting principally of methane resulting from processing gas. The term "gas plant products" will refer to natural gas liquid products collectively,

7/ The CDM goes on to state that "natural condensate (drip gasoline) or other liquids recovered from the natural gas stream in normal lease separators, heaters, scrubbers, dehydration units, or other facilities designed for separating the gas from produced crude, condensate or water, is not entitled to a manufacturing allowance." It is unnecessary to consider this restriction in the present dispute.

(ethane, propane, butane, pentane, etc.) and other products also produced by a processing plant (carbon dioxide, sulfur, nitrogen, etc.).

(Revision of Gas Royalty Valuation Regulations and Related Topics, Notice of Proposed Rulemaking, 52 FR 4734-35 (Feb. 13, 1987)). Thus, MMS indicated that the pre-amendment regulations did not consider "processing" to include removal of nonhydrocarbons.

Comparing the post-1988 and pre-1988 regulations, MMS expressly observed that the removal of H₂S from a natural gas stream is not "processing" (and therefore not deductible) under the old regulation: "Paragraph (d) would set forth the long-established principle that no processing cost deduction would be allowed for the costs of placing lease products in marketable condition. For example, if hydrogen sulfide is removed from a gas stream and flared, no processing cost deduction would be allowed." *Id.* at 52 FR 4740. The new regulations adopt a new rule only if the hydrogen sulfide is processed into sulphur and sold, or "processed into a gas plant product." *See Id.*; 30 CFR 206.158(d)(1) (1988).

"Treatment" of production connotes the removal or extraction of chemical impurities or contaminants in the gas stream that must be removed to render gas of marketable quality or place it in a marketable condition. Commentators have recognized that "impurities are often associated with petroleum (the sulfur compound that contaminates sour gas and oil is one), and these should be removed prior to marketing the product." 1 Williams and Meyers, Oil And Gas Law § 101 (Supp. 1990). As noted above, "sour"

gas is natural gas contaminated with chemical impurities, notably hydrogen sulfide or other sulphur compounds. Hydrogen sulfide is not a liquid hydrocarbon, as it is composed of more than "only hydrogen and carbon." See A Dictionary of Mining, Mineral and Related Terms 562 (1968). Thus, its removal does not fall within the meaning of the term "processing" as it is used in the pre-1988 regulations. We hold that sweetening natural gas to remove hydrogen sulfide is not processing, but is rather treatment.

Appellants employ the term "purifying" or "purification" to describe the removal of H₂S, rather than "treatment." They have not shown, however that employment of those terms would necessitate a different result. There is no doubt that hydrogen sulfide is an "impurity." "Purification" and "treatment" are synonymous in that both contemplate the removal of impurities or contaminants. See, e.g., 18 CFR 201.356 and 201.363.

The argument that the 88-percent adjustment represents plant fuel and losses is unavailing. The Unit operator has represented that the "principal contaminant at this time [that made] the gas unmarketable [was] H₂S rather than CO₂" and stated that the gas had to be processed even for use as fuel gas due to the high H₂S content. Appellants do not contend that the costs represented in the 88-percent factor were incurred as a result of "processing," that is, extracting natural gas liquids products from the natural gas in its natural state. To the contrary, the opposite conclusion is warranted. Chevron and Exxon's respective gas purchase contracts with Union do not authorize Union to extract liquefiable hydrocarbons from wet gas or casinghead gas (i.e., to process the gas). Nor does the price provision in

the respective contracts detail separately a price for the sale of extracted liquid hydrocarbons.

[2] In any event, any plant fuel and losses costs at the Battles Plant would appear to have been incurred in connection with treating the natural gas to reduce the H₂S concentration so that the treated gas could be used in Union's facilities. Because the costs are incurred as a result of treating the natural gas to remove the H₂S, they cannot be deducted nor can an allowance be granted therefor. It is irrelevant who performs the treatment or the activities necessary to place the gas in marketable condition, or that title may have passed from the Federal lessee prior to undertaking the activity necessary to place the gas in marketable condition.

Appellants assert that their gas is marketable in its unconditioned state and, thus, it is not necessary to place it into a marketable condition prior to sale (Chevron Statement of Reasons before the Director of MMS at 6-7). Appellants reason that, if the gas is marketable in an unconditioned state when it is passed to Union at the custody points or "at the well," the costs of removing hydrogen sulfide cannot properly be deemed costs of placing it in a marketable condition.

Appellants have submitted no evidence in support of their assertion that the gas is actually being marketed in its unconditioned state, and statements by Union representatives to MMS (quoted above) directly contradict such assertions. It is irrelevant that Union, rather than appellants, actually performed the treatment necessary to place the gas in marketable

condition, or that title may have passed from the Federal lessee prior to undertaking the activity necessary to place the gas in marketable condition. Union purchased the gas from appellants on condition that Chevron and Exxon pay for placing it in a marketable condition. Clearly, in these circumstances, appellants cannot be said to have been marketing the gas in its unconditioned state.

Relying on United States v. General Petroleum, 73 F. Supp. 225 (S.D. Cal. 1947), appellant Exxon contends that royalty must be based on the "value at the well" and avers that the sale to Union occurred "at the well" because title passed at the custody transfer point or at the well, prior to desulphurization and purification (Exxon Statement of Reasons at 5-6). An agreement between buyer and seller on a place for title to pass (while effectively passing title) is not conclusive for the purposes of laws extrinsic to the contract. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 233 (5th Cir. 1984), cert. denied, 471 U.S. 1005 (1985); see also Arco Oil & Gas Co., 109 IBLA 34, 39 (1989) (holding that the point of transfer of title to a pipeline was not the "first available market opportunity"). 8/ Thus, in the instant case, it cannot be said that the

8/ In Piney Woods, the Fifth Circuit recognized that a reference in a lease to the term "sold at the well" need not be controlled by the point at which title passes in the sales contract and concluded that gas sold by Shell was not "sold at the well," even though the sales contracts provided that title to the gas passed on or near the leased premises. Pivotal to the court's holding was the finding that, although title passed and metering occurred in the field, the seller bore the cost of sweetening the sour gas, so that the buyer effectively only paid for the cost of sweet gas. Id. at 231. In other words, if the seller bears costs beyond those associated with production, such as for transportation or treatment, the gas is not being sold "at the well." Here, the price paid by Union was not merely for unrefined production; it included adjustments for the costs of

transfer of title to the sour gas while it was still in its untreated condition meant that appellants were marketing the untreated gas. Although title may have passed and metering may have occurred before the gas went to the Battles Plant for sweetening, the fact that appellants bore the costs of sweetening meant that they were effectively marketing sweetened gas.

Appellants, noting that the gas was not required by contract to be "suitable for pipeline transmission" or of "pipeline quality," assert that the gas met contract specifications in its natural state (Chevron Statement of Reasons before the Director of MMS at 7-8; Exxon Statement of Reasons at 3-4). As a result, they contend, the instant case is distinguishable from California Co. v. Udall, 296 F. 2d 384, 388 (D.C. Cir. 1961), where the gas was not required to meet pipeline transmission specifications. In that case, certain costs were disallowed as deductions from the amount on which Federal royalty was calculated as costs of placing the gas in a marketable condition. See id. at 387-88.

We note initially that we are not persuaded that the sole basis for MMS's authority to disallow costs of sweetening is provided by California Co. v. Udall, supra. The regulations at 30 CFR 250.42 (1987) provide that authority. Thus, any differences between the facts in California Co. and the instant case do not render MMS' decision unsupported by authority.

fn. 8 (continued)

treatment. Chevron and Exxon, as sellers, bore these costs, so that the sale cannot be regarded as having been "at the well."

Because Piney Woods involved a private lease not governed by 30 CFR 250.42, the questions of the distinction between "treatment" and "processing" and the lessor's obligation to share in costs of same did not arise. The consequences of the court's holding regarded "sale at the well" were entirely different, arising as they did from construction of private lease royalty provisions different from those at issue here.

The issue of what constitutes "treatment" in a Federal royalty context and MMS' authority regarding the allocation of the costs of treatment was recently reviewed by the Fifth Circuit Court of Appeals. The court concluded that "measuring, gathering, compressing, sweetening, and dehydrating" constitute "treatment" and that MMS' requirement that costs of such treatment be excluded from the computation of royalty is "entirely reasonable and permissible." Mesa Operating Ltd. v. U.S. Department of the Interior, 931 F.2d 318 (5th Cir. 1991).

In any event, we do not find that the record supports the assertion that the gas as produced met contract specifications. Appellants were required under the gas purchase contracts in this case to "deliver the gas to the delivery points in its natural state." Union was not obligated to accept deliveries of gas not meeting standard quality specifications and could refuse deliveries of same (Chevron-Union Gas Purchase Contract at 3; Exxon-Union Gas Purchase Contract at 4). However, the record discloses that Union elected to take the gas even though these specifications were consistently not met. Union has made it clear that the gas in fact fails to meet gas quality specifications in the contract, and that it cannot use the gas in its natural state. Evidently owing to its ability to sweeten the gas at its plant (at appellants' expense), Union has agreed to accept deliveries of gas notwithstanding its sour state. The fact that Union does accept the gas does not show that the gas meets the quality specification or that it is marketable in its natural state; it merely means that Union has not exercised its right to reject the gas. See Chevron-Union Gas Purchase Contract at 4; Exxon-Union Gas Purchase Contract at 5.

Exxon's reliance on General Petroleum, *supra*, is misplaced. That case did not specifically deal with the "treatment" of production, it dealt with a classic example of "manufacturing" or "processing," for which an allowance is permitted. Acceptance of the principles established in this case without distinguishing between costs of "treatment" and "processing" would require this Board to disregard 30 CFR 250.42 (1987), barring the Government from sharing in the cost of treatment. Duly promulgated regulations have the force and effect of law and are binding on the Department and this Board. Conoco, Inc. (On Reconsideration), 113 IBLA 243, 249 (1990), and cases cited.

Chevron argues that MMS should not look beyond the terms of the sales contract with Union, noting that the post-1988 regulations require acceptance of proceeds under arm's-length contracts as the basis for establishing the value of production for royalty purposes (Chevron Statement of Reasons before the Director of MMS at 2-6). The Director's decision was properly predicated on the application of the regulation in effect in 1987. The post-1988 regulations are not applicable retroactively. BWAB, Inc., 108 IBLA 250, 257 n.2. (1989); Revision of Gas Royalty Regulations and Related Topics, Final Rule, 53 FR 1230 (Jan. 15, 1988).

Chevron also cites 30 CFR 206.150 (1987), which requires that MMS give due consideration to several factors, including price received by lessee. The Department's acceptance of gross proceeds or the price received by lessee as the selected method for valuation under 30 CFR 206.150 (1987) must be construed in concert with 30 CFR 250.42 (1987),

also in effect during the relevant period. The fact that MMS may have accepted as "value" proceeds received under an arm's-length contract under the pre-1988 regulations does not make an otherwise nondeductible cost deductible.

In summary, we hold that where the Federal lessee directly or indirectly bears the costs of "treatment," it is irrelevant that such treatment is performed by someone other than the lessee (Placid Oil Co., 70 I.D. 438 (1963)), or that title has passed from the Federal lessee prior to undertaking of the activity necessary to place the gas in marketable condition. Big Piney Oil & Gas Co., A-29895 (July 27, 1964). Costs of "treatment" are not deductible from the amount on which royalty is calculated or otherwise chargeable against the Federal royalty interest. 30 CFR 250.42 (1987).

Accordingly, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 CFR 4.1, the decisions appealed from are affirmed.

David L. Hughes
Administrative Judge

I concur:

James L. Byrnes
Administrative Judge

October 2, 1992

IBLA 88-233, 88-234	:	MMS 87-0335-OCS;
	:	MMS 87-0321-OCS
EXXON CO., U.S.A.	:	
CHEVRON U.S.A., INC.	:	Outer Continental Shelf Oil
	:	and Gas Lease Royalty
	:	
	:	Petition for Reconsideration
	:	Granted
	:	
	:	Decision Reaffirmed as Modified

ORDER

On November 15, 1991, we issued our decision in the above-captioned matter, Exxon Co., U.S.A., 121 IBLA 234, 98 I.D. 409 (1991), affirming decisions of the Director, Minerals Management Service (MMS), disallowing deductions from the royalty basis for certain costs of treating gas produced from Federal offshore oil and gas leases. The details of the dispute are set out in that decision and need not be repeated here.

On January 14, 1992, Chevron U.S.A., Inc. (Chevron), filed a petition for reconsideration of that decision. By letter also filed on January 14, Exxon Company, U.S.A. (Exxon) notified the Board that it was requesting reconsideration, adopting the reasons set forth by Chevron in its petition.

Chevron contends that the decision is in error by distinguishing between whether or not a gas plant product is a hydrocarbon or

non-hydrocarbon for purposes of deducting a processing allowance (also known as a "manufacturing allowance") from Federal royalty payments under 30 CFR 206.152(a)(2) (1987). Chevron contends that the appropriate distinction regarding deduction of processing allowances is whether or not the particular gas plant product is extracted from the wet gas stream and marketed commercially, thereby producing a substance on which royalty is due. Chevron indicates that MMS has traditionally allowed a manufacturing allowance of up to two-thirds of the value of sulfur manufactured from wet gas, presumably if and when the manufactured sulfur is sold. It voices concern that our decision in Exxon, U.S.A., Inc., supra, will result in abandonment by MMS of that practice, and that MMS will now attempt to collect additional royalties on sulfur and accompanying late payment charges.

Referring to various authorities, we concluded in the decision in question that "processing," as it was used in the pre-1988 regulations (including 30 CFR 206.152(a)(2) (1987)), embraced only the removal of hydrocarbon liquids from the natural gas stream. Exxon Co., U.S.A., 121 IBLA at 244, 98 I.D. at 413. ^{1/} The clear import of that discussion is, as Chevron

^{1/} The discussion in question was that summarized in the third sentence of Headnote 1 of the decision: "The sulphur contaminants are not liquid hydrocarbons, so that their removal is not 'processing' under 30 CFR 206.152 (1987)." Also, we stated as follows in note 6 of the decision:

"The Director held that what distinguishes treatment and processing is the creation of 'a new, chemically distinct product.' While MMS' assertion may be correct in the post-1988 regulations, we can find no support for this interpretation in regulations in effect in 1987, the Conservation Division Manual, or Board precedent."

Exxon Co., U.S.A., 121 IBLA at 243 n.6, 98 I.D. at 414 n.6.

points out, that no "processing allowance" could be allowed under 30 CFR 206.152(a)(2) (1987), for the extraction of elemental sulfur from the gas, as sulfur is not a hydrocarbon, as it is not composed of "only hydrogen and carbon." See A Dictionary of Mining, Mineral & Related Terms, 562 (1968); Exxon Co., U.S.A., 121 IBLA at 246, 98 I.D. at 415.

In its answer, MMS acknowledges that it "does not distinguish between hydrocarbons and non-hydrocarbons in determining whether to grant a processing allowance." Rather, MMS explains, it "determines if the gas plant product was 'manufactured' and if an allowance is necessary to arrive at the value of the product." In conclusion, MMS admits that, "when processing * * * results in the recovery of a manufactured product such as sulfur * * *, its value for royalty purposes is reduced by the costs of manufacture in the form of a processing allowance" (MMS Answer at 2). MMS does not specify the amount of the "processing allowance" or any legal authority therefor, but it is likely that it refers to the "reasonable allowance" of up to "two-thirds of the value of the substances extracted" provided for by 30 CFR 206.152(a)(2) (1987).

In view of Chevron's demonstration that MMS has in the past followed a policy at variance from that described in dictum in Exxon Co., U.S.A., supra, and MMS' apparent agreement with that showing, we deem it appropriate to strike those portions of the decision stating or implying that the

processing allowance of 30 CFR 206.152(a)(2) (1987) applies only to extraction and sale of liquid hydrocarbons. 2/

However, we adhere to our holding that MMS properly disallowed the 12-percent adjustment made by Exxon and Chevron for costs associated with removal of H₂S gas, as those costs were "costs of treatment" and, as such, not deductible from royalty basis under 30 CFR 250.42 (1987). Exxon Co., U.S.A., 121 IBLA at 247, 98 I.D. at 416. Even if a "processing allowance" might properly be granted under 30 CFR 206.152(a)(2) (1987), for extracting non-hydrocarbons from the gas, Chevron does not allege that the costs represented in that factor were incurred as a result of "processing" the gas for recovery of constituent products. 3/ See Exxon Co., U.S.A., 121 IBLA at 246, 98 I.D. at 416. The fact that a portion of the costs of extracting sulfur from the gas stream might, in circumstances not presented here, be regarded as a cost of processing entitling a lessee to a limited deduction (up to two-thirds of the value of any sulfur extracted) in no way alters our holding that MMS properly found those costs in this case to be costs of "treatment" and, as such, not deductible.

2/ Although we do not repudiate that statement, we agree that the question of the applicability of 30 CFR 206.152(a)(2) (1987) to the extraction of liquid hydrocarbons from the gas stream may be properly dealt with only in the context of an appeal directly challenging the granting or denial of such allowance where sulfur or other non-hydrocarbon is being extracted and sold. Such was not the case here. Chevron acknowledges in its petition that the hydrogen sulfide (H₂S) gas was not processed into sulfur and sold, but was instead treated as a waste product and disposed of (Petition at 4).

3/ As noted above, it expressly acknowledges that the gas was not processed for the recovery of sulfur.

Accordingly, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 CFR 4.1, the petition for reconsideration is granted, and our decision in Exxon Co., U.S.A., supra, is reaffirmed as modified by this order.

David L. Hughes
Administrative Judge

I concur:

James L. Byrnes
Chief Administrative Judge

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